PEDEVCO CORP
Form 10-K/A
April 19, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A
(Amendment No. 1)

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2012

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: 000-53725

PEDEVCO Corp.
(Exact Name of Registrant as Specified in Its Charter)

Texas	22-3755993
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

4125 Blackhawk Plaza Circle, Suite 201
Danville, California 94506
(Address of Principal Executive Offices)

(855) 733-3826
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:
None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $0.001 par value per share

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the

Act. Yes ¨ No þ

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	o	Accelerated filer	o
Non-accelerated filer	o	Smaller reporting company	þ

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 29, 2012 based upon the closing price reported on such date was approximately $3,364,034. Shares of voting stock held by each officer and director and by each person who, as of June 29, 2012, may be deemed to have beneficially owned more than 10% of the outstanding voting stock have been excluded. This determination of affiliate status is not necessarily a conclusive determination of affiliate status for any other purpose.

APPLICABLE ONLY TO ISSUERS INVOLVED IN BANKRUPTCY PROCEEDINGS DURING THE PRECEDING FIVE YEARS:

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ¨ No ¨

As of April 18, 2013, 41,739,965 shares of the registrant's common stock, $.001 par value per share, were outstanding

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EXPLANATORY NOTE

This Annual Report on Form 10-K/A is being filed as Amendment No. 1 to our Annual Report on Form 10-K ("Amendment No. 1"), which amends and restates certain parts of our Annual Report on Form 10-K for the year ended December 31, 2012 (the "Annual Report"), originally filed on March 25, 2013 with the Securities and Exchange Commission.

This Amendment No. 1 restates the following items:

Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations;
Part II, Item 8. Financial Statements and Supplementary Data;
Part II, Item 9A. Controls and Procedures; and
Part IV, Item 15. Exhibits and Financial Statement Schedules.

This Amendment No. 1 is being filed to restate the financial statements of PEDEVCO Corp. as of December 31, 2012 (i) to properly classify the issuance of 368,345 shares of our Series A Preferred Stock to a related party as a stock subscriptions receivable rather than a note receivable and (ii) to properly present on the balance sheet and the statement of stockholders' equity the classification of the shares of Series A Preferred Stock issued and outstanding and the par value and additional paid in capital for the 1,666,667 shares of Series A preferred stock presented outside of shareholders' equity (due to the redemption of such shares being outside of our control). In addition, this Amendment No. 1 includes expanded disclosure under Part II, Item 9A, Controls and Procedures, to include a statement identifying the framework used by management to evaluate the effectiveness of our internal control over financial reporting, and to include a statement that our internal control over financial reporting is not effective.

As required by Rule 12b-15 under the Securities Exchange Act of 1934, as amended, new certifications by our principal executive officer and principal financial and accounting officer are filed herewith as exhibits to this Amendment No. 1. This Amendment No. 1 also includes a re-issued audit report of GBH CPAs, PC.

Impact of Restatement

A summary of the effects of this restatement to the financial statements included within this Amendment No. 1 is presented under Note 5, "Restatement of Financial Statements," to the consolidated financial statements of PEDEVCO Corp.

Special Note Regarding Amendment No. 1

Except for the Items noted above, no other information included in the original Annual Report is being amended or updated by this Amendment No. 1. This Amendment No. 1 continues to describe the conditions as of the date of the original Annual Report and, except as contained therein, we have not updated or modified the disclosures contained in the original Annual Report. Accordingly, this Amendment No. 1 should be read in conjunction with our filings made with the Securities and Exchange Commission subsequent to the filing of the original Annual Report, including any amendment to those filings.

PART II

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the consolidated financial statements and related notes appearing elsewhere in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution you that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. See "Risk Factors" and "Forward Looking Statements."

On July 27, 2012, we completed our acquisition of Pacific Energy Development Corp., which we refer to as Pacific Energy Development. The acquisition was accounted for as a "reverse acquisition," and Pacific Energy Development was deemed to be the accounting acquirer in the acquisition. Because Pacific Energy Development Corp. was deemed the acquirer for accounting purposes, the financial statements of Pacific Energy Development are presented as the continuing accounting entity and the below discussion solely relates to the financial information of Pacific Energy Development as the continuing accounting entity.

Overview

We are an energy company engaged in the acquisition, exploration, development and production of oil and natural gas resources in the U.S., with a primary focus on oil and natural gas shale plays and a secondary focus on conventional oil and natural gas plays. Our current operations are located primarily in the Niobrara Shale play in the Denver-Julesburg Basin in Morgan and Weld Counties, Colorado and the Eagle Ford Shale play in McMullen County, Texas. We also hold an interest in the North Sugar Valley Field in Matagorda County, Texas, though we consider this a non-core asset.

We have approximately 10,224 gross and 2,774 net acres of oil and gas properties in our Niobrara core area. Our current Eagle Ford position is a 3.97% working interest in 1,331 acres. Condor Energy Technology LLC, which we jointly own and manage with an affiliate of MIE Holdings Corporation as described below, operates our Niobrara interests, including three gross wells in the Niobrara asset with current daily production of approximately 494 BOE (150 BOE net). We believe our current assets could contain a gross total of 197 drilling locations.

We also have agreements in place (subject to customary closing conditions) for acquisitions and future operations in the Mississippian Lime play in Comanche, Harper, Barber and Kiowa Counties, Kansas and Woods County, Oklahoma. See "Recent Developments - Mississippian Opportunity (Pending Acquisition)." If the proposed acquisition of the Mississippian asset is completed, upon closing, we will have a 100% operated working interest in 7,006 gross (6,763 net) acres, and will hold an option to acquire an additional 7,880 gross (7,043 net) acres through May 30, 2013. We believe the Mississippian asset could contain a gross total of 84 drilling locations.

We believe that the Niobrara, Eagle Ford and Mississippian Shale plays represent among the most promising unconventional oil and natural gas plays in the U.S. We will continue to seek additional acreage proximate to our currently held core acreage. Our strategy is to be the operator, directly or through our subsidiaries and joint ventures, in the majority of our acreage so we can dictate the pace of development in order to execute our business plan. The majority of our capital expenditure budget for 2013 will be focused on the acquisition, development and expansion of these formations.

Detailed information about our business plans and operations, including our core Niobrara, Eagle Ford and Mississippian assets, is contained under "Business" in Part I, Item 1 above.

How We Conduct Our Business and Evaluate Our Operations

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe have significant appreciaion potential. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives.

We will use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- realized prices on the sale of oil and natural gas, including the effects of our commodity derivative contracts;
- oil and natural gas production and operating expenses;
- capital expenditures;
- general and administrative expenses;
- net cash provided by operating activities; and
- net income.

Production Volumes

Production volumes will directly impact our results of operations. We currently have minimal production, all from the initial producing well associated with the Niobrara asset, three gross producing wells associated with our Eagle Ford asset, and three gross producing wells associated with our North Sugar Valley field, but expect to increase production assuming drilling success in the future.

Factors Affecting the Sales Price of Oil and Natural Gas

We expect to market our crude oil and natural gas production to a variety of purchasers based on regional pricing. The relative prices of crude oil and natural gas are determined by the factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. In addition, relative prices are heavily influenced by product quality and location relative to consuming and refining markets.

Oil. The New York Mercantile Exchange-West Texas Intermediate (NYMEX-WTI) futures price is a widely used benchmark in the pricing of domestic crude oil in the U.S. The actual prices realized from the sale of crude oil differ from the quoted NYMEX-WTI price as a result of quality and location differentials. Quality differentials to NYMEX-WTI prices result from the fact that crude oils differ from one another in their molecular makeup, which plays an important part in their refining and subsequent sale as petroleum products. Among other things, there are two characteristics that commonly drive quality differentials: (a) the crude oil's American Petroleum Institute, or API, gravity and (b) the crude oil's percentage of sulfur content by weight. In general, lighter crude oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value and, therefore, normally sell at a higher price than heavier oil. Crude oil with low sulfur content ("sweet" crude oil) is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content crude oil ("sour" crude oil).

Location differentials to NYMEX-WTI prices result from variances in transportation costs based on the produced crude oil's proximity to the major consuming and refining markets to which it is ultimately delivered. Crude oil that is produced close to major consuming and refining markets, such as near Cushing, Oklahoma, is in higher demand as compared to crude oil that is produced farther from such markets. Consequently, crude oil that is produced close to major consuming and refining markets normally realizes a higher price (i.e., a lower location differential to NYMEX-WTI).

In the past, crude oil prices have been extremely volatile, and we expect this volatility to continue. For example, the NYMEX-WTI oil price ranged from a high of $113.93 per Bbl to a low of $75.67 per Bbl during the year ended December 31, 2011 and from a high of $108.84 per Bbl to a low of $77.69 per Bbl during the year ended December 31, 2012.

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Natural Gas. The NYMEX-Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the U.S. Similar to crude oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX-Henry Hub price as a result of quality and location differentials. Quality differentials to NYMEX-Henry Hub prices result from: (a) the Btu content of natural gas, which measures its heating value, and (b) the percentage of sulfur, CO2 and other inert content by volume. Wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of natural gas liquids (NGLs). Natural gas with low sulfur and CO2 content sells at a premium to natural gas with high sulfur and CO2 content because of the added cost to separate the sulfur and CO2 from the natural gas to render it marketable. Wet natural gas is processed in third-party natural gas plants and residue natural gas as well as NGLs are recovered and sold. Dry natural gas residue from our properties is generally sold based on index prices in the region from which it is produced.

Location differentials to NYMEX-Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds. Generally, these index prices have historically been at a discount to NYMEX-Henry Hub natural gas prices.

In the past, natural gas prices have been extremely volatile, and we expect this volatility to continue. For example, the NYMEX-Henry Hub natural gas price ranged from a high of $4.92 per MMBtu to a low of $2.84 per MMbtu during the year ended December 31, 2011, and from a high of $3.20 per MMBtu to a low of $1.82 per MMBtu during the year ended December 31, 2012.

Commodity Derivative Contracts. We expect to adopt a commodity derivative policy designed to minimize volatility in our cash flows from changes in commodity prices. We have not determined the portion of our estimated production, if any, for which we will mitigate our risk through the use of commodity derivative instruments, but in no event will we maintain a commodity derivative position in an amount in excess of our estimated production. Should we reduce our estimates of future production to amounts which are lower than our commodity derivative volumes, we will reduce our positions as soon as practical. If forward crude oil or natural gas prices increase to prices higher than the prices at which we have entered into commodity derivative positions, we may be required to make margin calls out of our working capital in the amounts those prices exceed the prices we have entered into commodity derivative positions.

Oil and Natural Gas Production Expenses. We will strive to increase our production levels to maximize our revenue. Oil and natural gas production expenses are the costs incurred in the operation of producing properties and workover costs. We expect expenses for utilities, direct labor, water injection and disposal, and materials and supplies to comprise the most significant portion of our oil and natural gas production expenses. Oil and natural gas production expenses do not include general and administrative costs or production and other taxes. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities may result in increased oil and natural gas production expenses in periods during which they are performed.

A majority of our operating cost components will be variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, we will incur power costs in connection with various production related activities such as pumping to recover oil and natural gas and separation and treatment of water produced in connection with our oil and natural gas production. Over the life of hydrocarbon fields, the amount of water produced may increase for a given volume of oil or natural gas production, and, as pressure declines in natural gas wells that also produce water, more power will be needed to provide energy to artificial lift systems that help to remove produced water from the wells. Thus, production of a given volume of hydrocarbons may become more expensive each year as the cumulative oil and natural gas produced from a field increases until, at some point, additional production becomes uneconomic.

Production and Ad Valorem Taxes. Texas regulates the development, production, gathering and sale of oil and natural gas, including imposing production taxes and requirements for obtaining drilling permits. For oil production, Texas currently imposes a production tax at 4.6% of the market value of the oil produced and an additional 3/16 of one cent per barrel of crude petroleum produced, and for natural gas, Texas currently imposes a production tax at 7.5% of the market value of the natural gas produced. Colorado imposes production taxes ranging from 2% to 5% based on gross income and a conservation tax ranging from 0.07% to 1.5% based on the market value of oil and natural gas production. Wyoming imposes production taxes at a base rate of 6% and conservation tax of 0.04% based on the market value of oil and natural gas production. Ad valorem taxes are generally tied to the valuation of the oil and natural gas properties; however, these valuations are reasonably correlated to revenues, excluding the effects of any commodity derivative contracts.

General and Administrative Expenses. General and administrative expenses related to being a publicly traded company include: Exchange Act reporting expenses; expenses associated with Sarbanes-Oxley compliance; expenses associated with our efforts to have our shares listed on the NYSE MKT; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; director and officer liability insurance costs; and director compensation. As a publicly-traded company, we expect that general and administrative expenses will continue to be significant.

Income Tax Expense. We are a C-corporation for federal income tax purposes, and accordingly, we are directly subject to federal income taxes which may affect future operating results and cash flows. We are also subject to taxation through our membership interests in our joint ventures, which are limited liability companies taxed as pass-through entities.

Results of Operations

As a result of the reverse acquisition, the financial statements of Pacific Energy Development prior to the merger are presented as the financial statements of the Company. The financial statements prior to the date of the merger represent the operations of pre-merger Pacific Energy Development only. After the date of the merger, the financial statements include the operations of the combined companies.

Comparison of the Year Ended December 31, 2012 with the Period from February 9, 2011 (inception) through December 31, 2011

Oil and Gas Revenue. We had total revenue of approximately $503,000 for the year ended December 31, 2012, comprised of approximately $357,000 in revenue generated after February 2012 from Pacific Energy Development's two producing wells in the Eagle Ford asset and one producing well in the Niobrara asset and approximately $146,000 in revenue generated after the merger on July 27, 2012 from the former Blast business ("Blast") operations. Prior to February 2012, Pacific Energy Development was focused on acquiring oil and natural gas properties, and did not yet generate any revenue. Consequently, oil and gas revenue were $-0- for the period from February 9, 2011 (inception) through the year ended December 31, 2011.

Lease Operating Expense. Operating expenses associated with the oil and gas properties were approximately $281,000 for the year ended December 31, 2012 comprised of approximately $176,000 for Pacific Energy Development and approximately $105,000 attributable to Blast after the merger on July 27, 2012. Prior to February 2012, Pacific Energy Development was focused on acquiring oil and natural gas properties, and did not yet generate any revenue. Consequently, well operating expenses were $-0- for the period from February 9, 2011 (inception) through the year ended December 31, 2011.

Selling, General and Administrative. Selling, general and administrative ("SG&A") expenses increased by $3,013,000 to $3,730,000 for the year ended December 31, 2012 compared to $717,000 for the period from February 9, 2011 (inception) through December 31, 2011. The increase was primarily due to increased staff, professional service fees, legal fees in connection with the Pacific Energy Development merger, and stock compensation expense in 2012 not applicable to 2011.

(in thousands)	For the Years Ended December 31, 2012	For the Years Ended December 31, 2011	Increase (Decrease)
Payroll and related costs	$ 1,682	$ 309	$ 1,373
Option and warrant expense	621	-	621
Legal fees and settlements	162	120	42
Professional services	910	155	755

Insurance	109	10	99
Travel & entertainment	111	75	36
Office rent, communications and other	135	48	87
	$ 3,730	$ 717	$ 3,013

Impairment of Goodwill. Management evaluated the amount of goodwill associated with the merger with Blast following the allocation of fair value to the assets and liabilities acquired and determined that the goodwill should be fully impaired and has reflected the impairment on the statement of operations as of the date of the merger.

Depreciation, Depletion and Amortization ("DD&A"). DD&A costs were approximately $131,000 for the year ended December 31, 2012, compared to $1,000 for the period from February 9, 2011 (inception) through December 31, 2011, as recording of depletion commenced in 2012 when the wells began producing revenue.

Gain on Sale of Equity Method Investments. In connection with the White Hawk Sale in May 2012, the Company recorded a gain of $64,000 representing the difference between the Company's carrying value of the 50% investment sold ($1,875,000) and the fair value of the net sale proceeds received from MIE Holdings ($1,939,000). There was no such sale in 2011.

Loss from Equity Method Investment. Loss from equity method investments was $358,000 in 2012, compared with $26,000 in 2011. The Company has two investments accounted for using the equity method, Condor and White Hawk, which was acquired in 2012. The increased loss was due primarily to costs associated with exploration of new, unproven areas within the Condor property and general and administrative costs incurred for a full year of Condor operations (Condor was formed in October of 2011), offset in part by the addition of White Hawk in 2012 which generated net income.

Interest Expense. Interest expense was $986,000 for the year ended December 31, 2012 compared to $13,000 for the period from February 9, 2011 (inception) through December 31, 2011, an increase of $973,000 from the prior period. This increase is primarily due to the amortization of $507,000 for debt discount and $63,000 of interest expense related to the Centurion note acquired from Blast in the merger; and $380,000 of interest incurred on the extension of the due date for a deferred payment related to the acquisition of the Eagle Ford property held in Excellong E&P-2, Inc. (now White Hawk Petroleum, LLC).

Gain on Debt Extinguishment. The Company recorded a loss of $160,000 for debt extinguishment in connection with modifications made to amounts borrowed from Centurion Credit Funding, LLC under the Note Purchase Amendment dated January 13, 2012 as a significant conversion feature was added to the terms of the note and the Company's Merger with Blast triggered the contingent conversion feature. The Company recorded a gain on debt extinguishment of $169,000 in connection with amounts forgiven by Centurion Credit Funding, LLC for the complete extinguishment of the outstanding debt during the year. The net gain on debt extinguishment for the year ended December 31, 2012 was approximately $9,000.

Loss on Settlement of Payable. During the year, the Company recorded a loss on a settlement of payable in the amount of $139,874 related to issuance of 279,749 shares of Series A preferred Stock in full satisfaction and release of our obligation to Esenjay.

Net Loss. Net loss increased by $11,249,000 to a net loss of $12,013,000 for the year ended December 31, 2012 compared to a net loss of $764,000 for the period from February 9, 2011 (inception) through December 31, 2011. This increase was primarily due to $6,820,000 for goodwill impairment, the increase in SG&A of $3,017,000 in 2012 as described above, increased loss from equity investments of $332,000, the debt discount amortization and interest of $578,000 for the Centurion note, loss on settlement of payable to Esenjay in the amount of $139,874, and $380,000 of interest expense as described above.

Liquidity and Capital Resources

Liquidity Outlook

We expect to incur substantial expenses and generate significant operating losses as we continue to explore for and develop our oil and natural gas prospects, and as we opportunistically invest in additional oil and natural gas properties, develop our discoveries which we determine to be commercially viable and incur expenses related to operating as a public company and compliance with regulatory requirements.

On October 10, 2012, we filed a Registration Statement on Form S-1 with the Securities and Exchange Commission ("SEC"), with a proposed $50 million underwritten public offering of our common stock (the "Pending Public Offering"). Subject to clearance by the SEC, we anticipate closing the Pending Public Offering in the second quarter of 2013, although there can be no guarantee that we will be able to close the Pending Public Offering, or, if closed, raise the full amount sought in the offering. We intend to use the net proceeds that we receive from the Pending Public Offering to fund capital expenditures for leasehold acquisitions and development as well as for general corporate purposes.

Our future financial condition and liquidity will be impacted by, among other factors, our ability to successfully complete the Pending Public Offering, the success of our exploration and appraisal drilling program, the number of commercially viable oil and natural gas discoveries made and the quantities of oil and natural gas discovered, the speed with which we can bring such discoveries to production, and the actual cost of exploration, appraisal and development of our prospects. Assuming the Pending Public Offering closes in a timely manner, we estimate that we will make capital expenditures, excluding capitalized interest and general and administrative expense, of approximately $38 million during the period from January 1, 2013 to December 31, 2013 in order to achieve our plans.

We expect the proceeds of the Pending Public Offering, cash flow from operations, proceeds from asset divestitures and our existing cash on hand will be sufficient to fund our planned capital expenditures until the end of 2013. Because the wells funded by our 2013 drilling plans represent only a small percentage of our potential drilling locations, we will be required to generate or raise additional capital to develop our entire inventory of potential drilling locations, if we elect to do so. We may seek additional funding through asset sales, farm-out arrangements, lines of credit and additional public or private equity or debt financings.

Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, timing of regulatory approvals, availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Historical Liquidity and Capital Resources

Prior to the completion of the merger with Blast, we raised approximately $11.5 million through the sale of Series A preferred stock, which we refer to as the Pacific Energy Development Offering. The Pacific Energy Development Offering closed on July 27, 2012.

The proceeds of the Pacific Energy Development Offering were used to purchase our Niobrara and Eagle Ford assets and for general working capital expenses. The Eagle Ford asset had two producing wells when purchased and we have been receiving revenues since March 2012 from those wells. A well was drilled and completed in July 2012 in the Niobrara asset, resulting in oil revenues from this well in the quarter ended September 30, 2012. In the last quarter of 2012, Condor drilled two additional wells for a total drilling cost (not including fracking or completion costs incurred in 2013) net to our interest of $0.85 million in the Niobrara asset.

We had total current assets of $2.8 million as of December 31, 2012, including cash of $2.5 million, compared to total current assets of $0.6 million as of December 31, 2011, including a cash balance of $176,000.

We had total assets of $11.1 million as of December 31, 2012 and $2.9 million as of December 31, 2011. Included in total assets as of December 31, 2012 and December 31, 2011 were $2.4 million and $0, respectively, of proved oil and gas properties subject to amortization and $0.9 million and $1.7 million, respectively, in unproved oil and gas properties not subject to amortization,.

We had current liabilities of $4.7 million as of December 31, 2012, compared to current and total liabilities of $2.1 million as of December 31, 2011.

We had negative working capital of $1.9 million, total shareholders' equity of $5.1 million and a total accumulated deficit of $12.8 million as of December 31, 2012, compared to negative working capital of $1.5 million, total shareholders' equity of $0.9 million and a total accumulated deficit of $0.8 million as of December 31, 2011.

Cash Flows from Operating Activities. Pacific Energy Development had net cash used in operating activities of $2,804,000 for the year ended December 31, 2012, which was primarily due to a $12,013,000 loss from continuing operations offset by $6,820,000 for impairment of goodwill arising from the merger, $621,000 of stock compensation expense, $508,000 of amortization of financing costs,$358,000 in share of equity investment net loss, $280,000 of preferred stock issued to extend debt maturity and accounted for as interest expense.

Cash Flows from Investing Activities. Pacific Energy Development had net cash used in investing activities of $3,742,000 for the year ended December 31, 2012. Cash was used for oil and gas property acquisitions in the amount of $1,500,000, the payment of obligations of our pre-merger company related to the merger in the amount of $454,000, and cash funded to White Hawk and Condor as notes receivable in the amount of $2,786,000. This usage of cash was partially offset by $1,000,000 received from the sale of 50% of the White Hawk subsidiary to an affiliate of MIE Holdings.

Cash Flows from Financing Activities. Pacific Energy Development had net cash provided from financing activities of $8,848,000 for the year ended December 31, 2012, which was due primarily to the sale of preferred stock.

Critical Accounting Policies

Our discussion and analysis of our financial condition and results of operations is based on our financial statements, which have been prepared in accordance with accounting principles generally accepted in the U.S. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We base our estimates on historical experience and on various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our most significant judgments and estimates used in preparation of our financial statements.

Revenue Recognition. All revenue is recognized when persuasive evidence of an arrangement exists, the service or sale is complete, the price is fixed or determinable and collectability is reasonably assured. Revenue is derived from the sale of crude oil. Revenue from crude oil sales is recognized when the crude oil is delivered to the purchaser and collectability is reasonably assured. We follow the “sales method” of accounting for oil and natural gas revenue, which means we recognize revenue on all natural gas or crude oil sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. A receivable or liability is recognized only to the extent that we have an imbalance on a specific property greater than our share of the expected remaining proved reserves. If collection is uncertain, revenue is recognized when cash is collected. We recognize reimbursements received from third parties for out-of-pocket expenses incurred as service revenues and account for out-of-pocket expenses as direct costs.

Equity Method Accounting for Joint Ventures. The majority of the Company’s oil and gas interests are held all or in part by the following joint ventures which are collectively owned with affiliates of MIE Holdings:

- Condor Energy Technology LLC, a Nevada limited liability company owned 20% by the Company and 80% by an affiliate of MIE Holdings. The Company accounts for its 20% ownership in Condor using the equity method; and

- White Hawk Petroleum, LLC, a Nevada limited liability company owned 50% by the Company and 50% by an affiliate of MIE Holdings. The Company accounts for its 50% interest in White Hawk using the equity method.

The Company evaluated its relationship with Condor and White Hawk to determine if either qualified as a variable interest entity ("VIE"), as defined in ASC 810-10, and whether the Company is the primary beneficiary, in which case consolidation would be required. The Company determined that both Condor and White Hawk qualified as a VIE, but since the Company is not the primary beneficiary of either Condor or White Hawk that consolidation was not required for either entity.